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June 13, 2013

Director, Air Enforcement Division
Office of Regulatory Enforcement
U.S. Environmental Protection Agency, Mail Code 2242-A
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001

Subject: *United States v Equilon Enterprises, LLC*
Civil Action Number H-01-0978
Southern District of Texas entered August 21, 2001

Flaring Incident Report – May 13, 2013
Shell Oil Products US, Puget Sound Refinery

Dear Sir or Madam:

Pursuant to Section VIII, Paragraph 136 of the consent decree in *United States v Equilon Enterprises LLC*, Civil Action Number H-01-0978, entered August 21, 2001 by the United States District Court for the Southern District of Texas, Shell Oil Products US submits the following information regarding an Amine Acid Gas Flaring Incident, as defined in Paragraph 120(d), that occurred at the Puget Sound Refinery. The incident was investigated and a detailed report listing the root causes is included in the attached Incident Report.

I certify under penalty of law that I have personally examined and am familiar with the information submitted herein and that I have made a diligent inquiry of those individuals immediately responsible for obtaining the information and that to the best of my knowledge and belief, the information submitted herewith is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

If you have any comments or questions regarding this information, please contact Tim Figgie at (360) 293-1525.

Sincerely,

Thomas J. Rizzo
General Manager

Enclosure

cc (w/enclosures):

Director, Air Enforcement Division
U.S. Environmental Protection Agency
c/o Matrix Environmental & Geotechnical Services
120 Eagle Rock Avenue, Suite 207
East Hanover, NJ 07936

Director
NWCAA
1600 South 2nd Street
Mount Vernon, WA 98273

John Keenan
Office of Air Quality (OAQ-107)
US EPA – Region 10
1200 Sixth Avenue
Seattle, WA 98101

FLARING INCIDENT REPORT

Type of Incident: ☒ **Acid Gas / SWSG** ☐ **Tail Gas** ☐ **Hydrocarbon**

At 16:00 May 13, 2013, a momentary loss of electrical power to the refinery resulted in Alky 1, Alky 2, Poly, HTU1, HTU2, HTU 3, and CRU 2 shutting down with subsequent amine acid gas (AAG) flaring during the restart efforts. The refinery SO2 limit of 500 lbs per day was exceeded.

While attempting to restart Hydrotreater Unit 2 (HTU 2) at 15:10 May 15, 2013 hydrocarbon liquid was carried over into the HTU2 off-gas amine absorber. This hydrocarbon continued to carry under into the Amine Recovery Units (ARU's). The hydrocarbon and amine mixture in the ARUs foamed over causing liquid to fill the downstream Sulfur Recovery Unit 3 (SRU3) knockout drums resulting in a high level trip of SRU3. SRU4 was on hot standby (no charge) at the time (because of low refinery acid/sour water gas rates). The wastewater strippers (WWS) on the Fluid Catalytic Cracking Unit (FCCU) were taken off-line to remove sour water gas (SWG) from the header. SRU operators reduced the knock out drum levels in order to return charge back to SRU3. Amine Acid Gas (AAG) was routed to the Flare Gas Recovery (FGR) unit until all feed could be taken back into SRU3. The refinery SO2 limit of 500 lbs per day was exceeded.

At 04:29 on May 16, residual hydrocarbon in the ARUs from the initiating event caused another foam-over and tripped SRU3 again on high knock out drum level. AAG was flared for 11 minutes. Sulfur plant operators placed all charge into SRU4 and left SRU3 on hot standby and kept the WWS down to stop sour water gas to the SRU's.

Acid gas is normally treated on the SRUs and H2S is removed by the methyldiethanolamine (MDEA) system. However, due to the SRU trips, the AAG was routed to FGR for H2S removal up to the available capacity. The captured H2S was routed back with the rich amine (regular DEA) system (Tank 104) to be treated in the ARUs. This increased the H2S load to the ARUs which caused reduced rich amine stripping in the ARUs resulting in an elevated concentration of H2S in the refinery fuel gas system. In an effort to improve H2S recovery fresh DEA was added to the ARU amine system.

Over the next three days operations purged the hydrocarbon in the ARU overhead accumulators to Tank 104 to skim off hydrocarbon. Entrained hydrocarbon in the amine from Tank 104 caused several foaming incidents of the absorbers which continued to affect the ARUs ability to treat the refinery fuel gas to H2S limits. As a result, the refinery fuel gas exceeded H2S limits on the following occasions: at 14:55 on May 16th and 17:11 on May 17th. In addition, the refinery fuel gas H2S limit of 50 ppm 24 hour rolling average was exceeded at 14:21 on May 17th and the flare gas 162 ppm H2S 3 hour rolling average limit was exceeded. There was also a one-hour exceedance of the flare limit of 1000 ppm SO2 corrected to 7% oxygen on May 15th at 16:00. Once the impact of the additional H2S in the DEA had passed and the hydrocarbon mixture was sufficiently segregated in Tank 104, H2S absorption improved and the refinery fuel gas returned to specifications.

Incident Start Date:	5/13/2013	**Incident Start Time:**	4:00 PM
Incident End Date:	5/17/2013	**Incident End Time:**	5:11 PM

Estimated Sulfur Dioxide Emissions: (Attach below):	1019	**Pounds**

SO2 lbs/hr = 0.995*(flare gas flow, MSCFH * 1000) * (Sulfur, vol% / 100) * (64.0648/379), where 0.995 is flare efficiency, 64 #/#-mole is the MW of SO2 and 379 is scf/#-mole

Steps taken to limit the duration and/or quantity of sulfur dioxide emissions:

Sour water gas was immediately removed from the SRU feed. Flare gas recovery compressors were operating to recover as much AAG as possible. Also, hydrocarbon was purged from the ARU absorber towers and sequestered in the slops compartment of the rich DEA system.

ANALYSIS OF INCIDENT AND CORRECTIVE ACTIONS

No additional information attached

Primary and contributing causes of incident:

The initiating root cause of this event was a power outage that occurred outside of the refinery's control and the subsequent hydrocarbon carry under from the HTU2 11F114 off-gas amine absorber during start up.

Analyses of measures available to reduce likelihood of recurrence (evaluate possible design, operational, and maintenance changes; discuss alternatives, probable effectiveness, and cost; determine if an outside consultant should be retained to assist with analyses):

To prevent a reoccurrence of this event the level alarm value on the overhead accumulator upstream of 11F114 (HTU-2 off gas amine absorber) was reduced.

Description of corrective action to be taken (include commencement and completion dates):

See above.

If correction not required, explain basis for conclusion:

See above.

The incident was the result of or resulted in the following (check all that apply):

- ☐ **Error from careless operation**
- ☐ **Equipment failure due to failure to operate and maintain in accordance with good engineering practice**
- ☐ **Sulfur dioxide emissions greater than 20 #/hr continuously for three or more consecutive hours**
- ☐ **Caused the number of Acid Gas or Tail Gas incidents in a rolling twelve-month period to exceed five**
- ☒ **None of the above**

Was the root cause identified as a process problem isolated within an SRP?

- ☐ **Yes (An optimization study of the affected SRP is required as part of the corrective actions identified above.)**
- ☒ **No**

The root cause of the incident was:

- ☐ **Identified for the first time since March 21, 2001**
- ☒ **Identified as a recurrence since March 21, 2001 (explain previous incident(s) below)**

Power failure

Was the root cause of the incident a malfunction?

- ☒ **Yes (describe below)**
- ☐ **No**

The initiating root cause of this event is suspected to be a power failure in conjunction with allowing the overhead accumulator level in the vessel upstream of the HTU2 off gas absorber to run over due to:

> Incorrect level transmitter span and alarms on the H2S stripper accumulator drum and lack of procedural guidance around when to start reflux on the H2S Stripper overhead accumulator.

Definition of Malfunction: ***Any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or failure of a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.***

REPORTING REQUIREMENTS

Submit initial report, supporting documents and assessment of stipulated penalties, if any, within 30 days of the incident to the EPA Regional Office and Northwest Clean Air Agency.

If at the time the first report is submitted (within 30 days of the incident), corrective actions have not been determined a follow-up report is required within 45 days of first report (unless otherwise approved by the EPA). Provide anticipated date of follow-up report.

Prepared By: _____James Steller _____ Date: ___June13, 2013___